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Photovoltaics Program
Technology Development and Applications
Lead Center

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Photovoltaics as a Terrestrial Energy Source: Volume II, System Value

Jeffrey L. Smith

October 1980

Prepared for
U.S. Department of Energy
Through an Agreement with
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ABSTRACT

This document, the second in a series of Jet Propulsion Laboratory (JPL) examinations of photovoltaic (PV) systems, their potential for terrestrial application, and JPL's role in their development, undertakes (1) to examine the assumptions and techniques employed by the electric utility industry and other electricity planners (especially the PV Program) to make estimates of the likely future value of photovoltaic systems interconnected with U.S. electric utilities, and (2) to summarize existing estimates of PV value and discuss their interpretation and limitations. PV value is defined as the marginal private savings accruing to potential PV owners: potential social benefits (e.g., pollution reduction) are not included. For utility-owned PV systems, these values are shown to be the after-tax savings in conventional fuel and capacity displaced by the PV output. For non-utility-owned (distributed) systems, the utility's savings in fuel and capacity must first be translated through the electric rate structure (prices) to the potential PV system owner. Base-case estimates, from several recent studies, of the average value of PV systems to U.S. utilities are presented (ranging from $40/W$_p$ to $1.00/W$_p$, 1980$). Non-base-case estimates are sometimes considerably higher as are most existing estimates for the value of residential grid-interconnected PV systems. The relationship of these results to the PV Program price goals and strategy of the Carter Administration is discussed; the usefulness of PV output quantity goals is reviewed.

FOREWORD

This is the second in a series of documents discussing the use of photovoltaic (PV) systems for terrestrial applications. The purpose of the series was to provide a forum for discussion of Jet Propulsion Laboratory (JPL) policy on the conduct of its photovoltaic projects, within the charter granted JPL by the Department of Energy's National Photovoltaics Program. These photovoltaic projects constitute a major part of JPL's Utilitarian Program. This Program applies skills developed in space exploration to problems of high national priority. JPL believes that its technical competence and success at managing complex research and development projects have wide applicability to many pressing issues of national scope.

While the overall intent of JPL's Utilitarian Program is straightforward, important questions surround the specific purposes, limitations, strategies and status of the individual projects, including the PV projects. It is hoped that the information presented here will aid policy formulation with respect to these questions.

As discussed in the introductory paper of this series (Reference 1), photovoltaic systems cannot now compete in grid-connected markets because they produce electricity at a cost more than 10 times the marginal cost of utility-supplied power. This has led the National Photovoltaics Program as formulated and implemented by the Carter Administration to adopt cost reduction as its primary strategy and to establish PV system and component price goals that will, in some circumstances, allow PV to compete successfully with utility-supplied power in U.S. electricity markets. Evaluations of the future of photovoltaics, especially of the role of the government Program in PV development, depend on two critical factors: Are the Program goals properly selected? What is the probability of attaining the goals and on what does that probability depend? This paper and the one to follow describe economic analyses that can aid understanding of these and other matters concerning the promise of photovoltaic electricity production.

The purpose of this volume is to delineate the techniques being developed for estimating future demand prices of grid-connected photovoltaic systems in the United States and to summarize results of the application of these techniques. The Massachusetts Institute of Technology Energy Laboratory has held prime responsibility in the National Photovoltaics Program for development of such techniques ard other economic analyses. Aerospace Corp. and Sandia National Laboratories, among others, play significant supporting roles in the PV Program for various economic analyses. JPL, in its PV Lead Center role, manages these PV Program efforts and performs independent analyses in support of the Lead Center's assessment and planning functions. Similar economic analyses are being conducted by several research groups across the country with respect to photovoltaics and other stochastic electrical generation sources with intermittent electricity production. This paper encompasses many of these efforts, but concentrates on PV Program and Jet Propulsion Laboratory activities.

The paper consists of two major sections. The first introduces concepts, assumptions, and approaches used in our analysis of future PV system prices. The second discusses estimates of the value of PV systems to their owners--their break-even prices.

ACKNOWLEDGEMENTS

This paper has benefited considerably from extensive discussions and written comments from many of my JPL colleagues, including Bud Schurmeier, T. W. Hamilton, R. G. Forney, R. P. O'Toole, M. E. Alper, K. M. Koliwad, D. H. Ebbeler, C. S. Borden, R. W. Easter, R. G. Chamberlain, P. Sutton and R. W. Aster. I would like to thank my editor, E. E. Sloman; my assistant, K. L. Hughes, and my secretary, A. M. Calvert.

CONTENTS

Tables

SECTION I

INTRODUCTION

Congress has mandated that the National PV Program conduct its activities to foster a private, competitive industry supplying PV systems that are "cost competitive with conventional electricity generating sources" (Reference 2). Accordingly, PV system price goals have been adopted by the Carter Administration PV Program that, if achieved and if the assumptions upon which the goals are based prove correct, will allow the profitable sale of PV systems by private suppliers to private purchasers.

Figure 1 is a simple depiction of a PV system marketplace in which potential system suppliers offer their products to potential buyers. In entering the transaction each supplier has in mind his required price which, if obtained (or exceeded), would allow him to pay all normal costs of doing business and to receive (or exceed) a stated return or profit on the equity invested in the business. Potential buyers are presumed to value the systems primarily according to how much they save on electricity costs. The potential buyer's break-even price is that price he could pay initially for the PV system and break-even compared with the costs of continuing to buy electricity from the best alternative source, considering all costs and benefits over the lifetime of the PV system.

If a buyer's break-even price is higher than or equal to the supplier's required price, there is a potential for a mutually beneficial sale, presumed to take place at the market purchase price (Figure 1). Thus the PV system price goals must be equal to or less than the price at which private purchasers will willingly demand photovoltaic systems and equal to or greater than the price at which private businesses will willingly supply PV systems.*

While the Program has produced estimates of the future profile of annual PV system sales volumes and predictions of the likely total deployment of PV systems at various dates in the future, these estimates are considerably more uncertain than break-even and required-price estimates, which are uncertain enough (see below). Furthermore, they add little to the quality of decisions on the future conduct of the Photovoltaic Program, which is the crux of a long-standing controversy over the proper specification of photovoltaic goals.

Should the Program adopt a specific quantity-of-output goal or a system price target? (Two commonly suggested quantity targets are: 500 MW_p installed annual production capacity by 1986 and 1 quad/year primary-fuel displacement by the year 2000.) Is there an advantage to setting both types of goals, as Congress has done? Answers to these questions can be derived from an examination of the types of decisions faced by Program management. Goals are selected to guide and aid these decisions, as well as to communicate the intentions of the Program.

*This formulation of system price goals in terms of private market prices and conditions can be interpreted to be seriously at odds with a socially optimal formulation due to the many market failures present in energy markets. See Appendix A for a brief discussion.

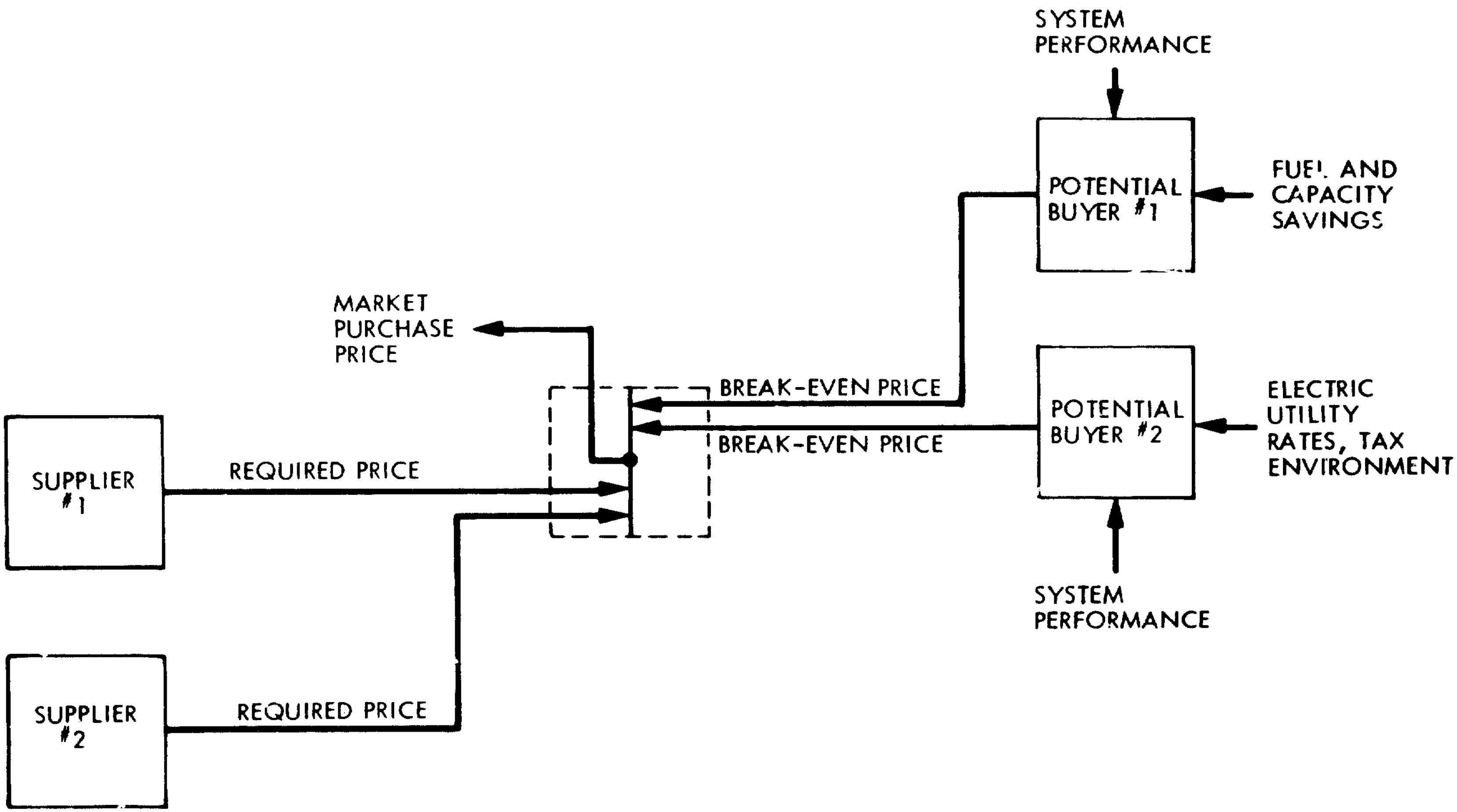

Figure 1. Model of a Private Photovoltaic Market Transaction

As discussed earlier (Reference 1) the PV Program is presently concerned primarily with technical developments. Decisions must be made on which collector technologies to pursue, which production processes to develop, which applications to emphasize, which system designs to undertake, etc. To a great extent the proper decisions on these questions depend upon the relative attractiveness of the resulting products in the various markets for which they are intended. This paper argues that break-even and required prices as formulated here are the most effective and desirable numerical method of gauging this relative attractiveness.

As emphasized in the first paper of this series (Reference 1), these measures are based on uncertain assumptions that, if incorrect, could lead to large changes in the realized competitiveness of PV systems even if the price goals are achieved. Nevertheless, the PV Program believes that price goals and associated analyses can significantly aid Program decision making and reduce uncertainties about the potential for beneficial development and utilization of PV systems.

On the other hand, quantity goals (specified in terms of megawatts of PV deployed in specific future years) presume control not only of factors affecting the potential attractiveness of PV systems but also of when and in what quantity these systems will actually be produced and sold. Excepting efforts directed at attaining the price goals, the types of government decisions that may affect the timing and level of future PV deployments include such things as tax incentives, loan guarantees, and large cost-shared demonstrations.* However, these activities are not appropriate for implementation now, since PV system and collector technology for grid-connected markets is too immature (see below), and are often not within the scope of PV Program management (i.e., they are reserved to Congress and to higher levels of the Administration). Furthermore, events beyond the purview of government action can render such market stimulation efforts impotent.

A goal set in terms of specific quantities of output in future years adds little significance to existing price goals and may or may not be compatible with them. Attainment of an output goal will be largely beyond the control of the Program, affected by many unforeseeable events (recessions, material shortages, trade restrictions) and by other government decisions.

For these reasons, primary goals have been specified in terms of system prices projected to be competitive under specified circumstances in private markets with conventional electricity sources. It is argued that attainment of these goals, in conjunction with the realization of the underlying assumption of the analysis, will create a potential for advantageous deployment of photovoltaic systems at levels sufficient to affect significantly and beneficially the future of U.S. bulk electricity production and use. It also leaves

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*The ability to speed up attainment of the price goals through increased research and development expenditures is limited severely by technical time constraints; the development schedule is already based on accelerated, parallel development efforts. Lack of sufficient financial support will quickly result in slippage of this schedule, however.

open the possibility of additional future government actions directed at specific quantities of PV deployment (e.g., tax incentives).

It has been argued, however, that Congressional and Administration decisions on the level of government expenditures for PV (and other energy technologies) should be based upon the predicted impacts of these technologies (that is, upon the predicted profile of future quantities of energy produced).

For this reason, projections of PV deployment were included by JPL in a Department of Energy (DOE) report submitted to Congress (Reference 3) using various assumptions concerning the future development and federal funding of photovoltaics. The usefulness of these projections is severely marred, however, by the simplistic assumptions forced on us by the overwhelming uncertainties involved in detailed long-term projections of this type. The likelihood is small that the quality of Congressional and Administration funding decisions will be improved by comparisons of year-specific quad (10^{15} Btu) impact predictions among the class of potential long-term electricity sources of which PV is a member.

While selection of proper goals for PV development is quite important, an evaluation of the likely success of photovoltaics is at least as dependent upon the probability that privately supplied PV system prices will fall sufficiently to meet the goals. The introductory paper highlighted the difficulties inherent in judgments about the extent of future cost reductions resulting from research and development activities. However, even if technical achievements are sufficient to lower current production costs to the goals, it is necessary that these lower required prices be reflected in actual market prices. This imposes the further requirement that the PV supply industry be competitive and near equilibrium.

Finally, the price elasticity of supply of inputs to the PV production process is of much interest. If any important inputs are limited in supply (are depletable or have upward-sloping supply curves) the price of photovoltaic systems may rise as rates of output and cumulative production rise, limiting the ultimate benefits from PV.

Thus, judgments as to the probability of sufficient system price reductions must involve not only detailed evaluations of technical prospects, but also assessments of the likely PV supply industry structure and evolution.

SECTION II

THE VALUE OF PHOTOVOLTAIC SYSTEMS

A. SYSTEM OWNERSHIP

If we are to estimate the value of PV systems to their potential owners, we must know who the owners are and what types of PV systems they are likely to prefer. The introductory paper argues that all major new sources of electricity in the developed world must compete with utility-supplied power. In addition, it appears very likely that grid interconnection, with the grid supplying backup and purchasing excess electricity, will become the dominant system configuration. While large penetrations of photovoltaic systems could increase the usefulness of electrical storage systems interconnected with the same utility, the opposite result holds for small PV penetrations. Electrical storage dedicated to storing PV output is unlikely to be either necessary or desirable in grid-connected applications (Reference 1, pp. 4-6).

Beyond that, however, the preferred system configuration, size, and ownership are in much doubt. Small dispersed systems mounted on residential or commercial rooftops owned by homeowners, utilities, or businesses may become attractive, or larger industrial and utility-owned central-station systems (e.g., ground-mounted) may become dominant. The attractiveness of photovoltaics will be influenced by the tax and financial situation of the owner. Are his energy costs deductible? Does he pay property tax on the solar system? Does he receive solar subsidies? How can he depreciate the system? How will he finance the system? Are revenues from sale of excess electricity taxable income? The potential attractiveness of PV systems must be evaluated for a wide variety of owners and applications.

A second set of complications is introduced by the nature of the photovoltaic product and its interaction with the competition--grid-supplied power. It is expected that grid-interconnected photovoltaic systems will supply to the grid ac electricity virtually identical in a technical sense with the conventionally produced kilowatt hours that the PV displaces. Thus, the social value (socially optimal only in the severely restricted sense discussed in Appendix A) of PV kilowatt hours can be defined as the the cost of producing those same kilowatt hours by the best alternative source, if PV is unavailable. That is, society should be willing to pay no more for PV electricity than the entire cost of producing the same product with the best alternative source.* Thus defined, the value of PV to society is a function solely of the cost of the competition.

In general, the PV Program has restricted its projections of the likely competitive sources to the actual projected capacity expansions of existing utilities, which until very recently have consisted almost exclusively of conventional electrical capacity (e.g., coal and nuclear). Thus, the value of a photovoltaic system is defined to be the combination of: (1) the savings of

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*Keeping in mind, of course, that these tradeoffs are always made at the margin. When large additions of PV systems are considered, confusion can arise between the marginal and average product of PV.

utility expenditures for conventional capacity, fuel, and other operating expenses that result from the photovoltaic system, and (2) the value of any changes in the costs of transmission and distribution occurring as a result of the system.* Published numerical estimates exist only for the first category of possible PV benefits, and these estimates are difficult to produce and suffer significant conceptual ambiguities. Nevertheless, it is the sum of these conventional utility savings in fuel, operation and maintenance (O&M), and capital (capacity) that constitute the principal existing numerical measure of the potential value of photovoltaics.

When these basic savings are translated into the actual savings realized by the system owner, they become the PV system break-even price for that owner. This is the price at which a photovoltaic system can be purchased and still cost no more than the best alternative method of accomplishing the same electricity production.**

B. UTILITY FUEL AND CAPACITY SAVINGS

For most customers a utility supplies more than simply a total quantity of kilowatt hours per period. Unless a customer has contracted for an interruptible supply and electricity rate, the utility also promises to supply kilowatt hours at precisely the time they are demanded. Viewed from the utility perspective, this means that the utility must be prepared not only to supply the total amount of energy demanded during a period, but also to have sufficient generation capacity to meet the rate of demand at any time. Since total demand seen by a utility can easily fluctuate by a factor of 2 or 3 over the course of a day or season, utilities have been led to construct a mix of generation sources: some that operate most of the time (base-load), others that operate cyclically (intermediate), and a final category that generates only briefly during system peaks (peaking capacity). Since base-load systems operate much of the time, it is important that their per unit fuel costs be minimized even if a significant capital cost penalty is incurred. Nuclear and coal are the most common base-load sources. The opposite holds for peaking

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*Apparently, PV may often be sited closer to the load it serves than present electricity sources. However, the significance of this possible benefit is uncertain as are the costs likely to be imposed by photovoltaics on utility-system operation and control.

**To be accurate, the sales price of the PV system can be no more than the present value of the utility operating and capacity savings over the life of the photovoltaic system as actually realized by the system owner minus the present value of all operations, maintenance, replacement and other recurring costs of the PV system and the costs of the grid interface. The actual comparison is between the present value of the the total costs incurred during the lifetime of the PV system (life-cycle costs) and the life-cycle costs of the next best alternative (Reference 4). However, the Multi-Year Program Plan (Reference 5) has chosen to express goals in terms of the installed PV system sales price (which necessitated subtracting the other components of life-cycle cost mentioned above), since it communicates a well-defined, easily understood concept.

systems (oil and gas turbines) that operate infrequently-- fuel costs are relatively unimportant.* Fairly simple economic comparisons based upon life-cycle cost per kWh of expected output can be made among conventional generation sources within each category.

Unfortunately, electric generation systems that exploit a resource whose supply is dependent on stochastic weather patterns--run-of-the-river hydro, PV, solar-thermal, wind--do not fit neatly into these categories. On one hand, they appear most like baseload systems in that their operating costs are low, since their fuel is "free." This implies that such systems will almost always be dispatched first--they should always be operated when available. On the other hand, the output is much more random and intermittent than that of conventional generators (which may be simply described as either "up" or "down"). Thus, the contribution of weather-dependent generators to the reliability of the grid is not directly comparable to that of conventional generators. Furthermore, the weather-dependent technologies cannot even be directly compared among themselves on a life-cycle cost per kWh basis because their outputs have different characteristic time profiles. In fact, some such technologies (e.g., solar) produce mostly during periods when power is more highly valued (daytime), while others may or may not (wind, hydro).

Since the outputs of weather-dependent sources exhibit partially random behavior and are always dispatched when available, they are effectively removed from the control of the utility dispatcher--they assume the character of a negative load on the system. This is often how they are treated in the analytical activities described below.

Traditional utility generation evaluation techniques have not had great need to evaluate either significant random variations in the shape of the load curve or weather-dependent technologies. To some extent it is necessary to extend techniques currently employed by the utility industry to make them applicable to PV and similar electricity sources. Since the time at which power is delivered affects significantly both the value of the fuel displaced and the value of the source's capacity (the capacity displaced or, equivalently, the contribution of the source to the grid's reliability), these extensions involve an elaboration of the conception of utility reliability as well as the techniques required to handle that elaboration and other difficulties.**

The computation of utility fuel and capital cost savings expected to result from a given quantity of photovoltaic systems interconnected with a particular utility can be accomplished in four steps, each of which consists of a computer simulation of the predicted phenomenon. The first step consists of simulation of the performance of the photovoltaic system(s) through time.

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*The costs and cycling times of plant start-up and shut-down also vary among the three conventional categories.

**As mentioned earlier, development of similar techniques for application to the same or related problems is proceeding at several locations across the country.

This produces an output profile of photovoltaic electricity over time, which can then be subtracted from the utility load curve to yield the net load faced by the utility.*

In the second step. the reliability of the grid including the PV system is calculated. If the utility system is found to be more reliable than it was before the addition of PV, conventional units are withdrawn from the generation mix until the reliability of the grid returns to its previous (arbitrary)** value. The present value of conventional plant deferral represents the value of capacity displaced by PV.

The third step involves the calculation of the production cost savings arising from the PV addition. To accomplish this, the dispatch of the newly configured grid is simulated and the total costs for fuel, maintenance, and operations are estimated. These are subtracted from the same results for the grid configuration without PV. This difference represents the short-run (fuel and O&M) costs that the PV saves. When the present value of these savings is added to the present value of the displaced investment in conventional capacity (calculated above) one has the present value of utility conventional generation cost savings resulting from the PV addition.

The final step is to search all possible combinations of generation mixes (with PV included) that satisfy the reliability constraint, looking for the mix that maximizes the total conventional savings. This mix is then defined as optimal.***

Each of these four steps is discussed in more detail below.

1. PV SYSTEM SIMULATION: LIFETIME COST AND PERFORMANCE

Predicting the performance of a hypothetical photovoltaic system is no easy task. Weather data, system design and performance parameters, and maintenance, cleaning and degradation effects over the life of the system are of major importance.

The performance of photovoltaic systems is a function of the available irradiance and of the temperature of the PV cells. Since these variables are a function of available sunlight (depending on location, time, cloud cover, atmospheric aerosols, and tilt angle) and other weather variables (ambient

*In addition, PV output and utility load are probably jointly determined (e.g., hot summer days have high insolation and high air conditioning loads). Thus, load data and weather data need to be matched.

**In fact, since the simulation is done as of some future date, the conventional units withdrawn are actually units that are currently planned but not yet built. Thus, as a result of the addition of PV, they are downsized, their construction is delayed or they simply become unnecessary.

***Several investigators have also attempted to include optimization of generation reliability rather than employing an exogenous reliability constraint, by considering the costs to electricity consumers of insufficient generation capacity.

temperature, wind speed) that vary significantly over the course of a day, it is essential that models of PV system performance employ short sampling intervals. JPL uses hourly samples for its system performance simulations for break-even price calculations. Hourly sampling intervals are also required for reliability and operating cost calculations when PV is present in the grid mix. For other purposes (e.g., transient investigations) much shorter intervals (every few seconds) may be required.

Probably the biggest source of uncertainty in our ability to predict PV system performance lies in the lack of sufficient appropriate weather data. This seriously complicates performance comparisons among system designs that respond differently to irradiance (e.g., flat-plate vs concentrator comparisons or fixed-tilt vs tracking comparisons). Several years of hourly weather data have been collected at 26 sites (Reference 6) across the nation by the National Weather Service, but there are serious concerns that the measurement instruments employed were often inaccurate. Much of the data is suspect or incomplete. Data is often recorded as total irradiance falling on a flat surface. The diffuse radiation and direct radiation components (which sum to total irradiance) are sometimes not recorded. While a number of new stations at universities and private companies have recently begun to record irradiance and weather data, the appropriateness and comprehensiveness of these data for PV Program purposes have not yet been determined. And even though the demand for electricity is correlated with weather conditions, as is PV output, simultaneously observed demand and weather data are rarely available.

In addition, the PV system design is important. What is the conversion efficiency and how is that a function of temperature? Does the system track? Is it self-shading at times? How efficient is the inverter at different input levels? How should modules and arrays be configured to minimize the effects of cell failure and electrical mismatch?

Finally, assumptions about the effects of age and weathering on the system must be made. Does the system have inherent degradation? At what rate? What failure modes are likely? How does system design interact with failures, e.g., does the system bypass defective modules that could become power sinks? Does the system have redundant series-parallel wiring? At what rate does dirt accumulate on the system and what effect does this have on performance? Should the arrays be cleaned? When? How does this improve performance? Is rain effective in cleaning modules? (Each of these questions can be investigated with JPL's Lifetime Cost and Performance (LCP) simulations.)

The PV simulation produces an hourly profile of simulated PV output. In practice usually only one year's output is simulated. This output is then subtracted from the hourly load curve of the utility in whose district the PV system (i.e. weather data) is assumed to be located to produce a net load curve. Conventional generation is then planned to serve this load.

2. UTILITY SIMULATION: RELIABILITY

Over the past 10 to 15 years, simulations of utility dispatch and production costs, reliability, and capacity expansion have become generally

accepted as useful planning tools.* While they apparently can increase the quality of utility decision making, they are not fully developed, especially simulations of grid reliability and capacity expansion.

The term reliability is used in this paper in a restricted sense--we refer only to the probability that the total available generation sources will be sufficient through time to meet the load of the utility.** A broader definition could include failures in the sub-transmission and distribution networks (failures in transmission lines from conventional generators are usually included in those units' forced outage rates), as well as problems with short-term stability and control of the utility system. Photovoltaic systems can have effects on both of these additional contributors to overall grid reliability. However, we concentrate here on the adequacy of generation sources.

In theory, a utility system is subject to failure at any moment due to lack of sufficient available generation sources. However, as a result of large fluctuations in daily and seasonal load profiles, the actual probability of insufficient capacity has traditionally been much higher at the system peaks than at the troughs. This fact, combined with the high dispatch control and the nature of forced outages of conventional capacity, has led to a fairly simple characterization of capacity sufficiency that is still employed by many of today's utilities--the reserve margin.

The reserve margin is the amount, expressed as a percentage, by which the capacity of a utility is projected to exceed the annual peak load on the system. The high operational control exhibited by conventional sources permits the assumption that except for forced outages (with fairly small probabilities attached to these) all system capacity can be made available to serve the annual system peak through proper maintenance scheduling. Most utilities also choose to preserve enough operational flexibility to survive the loss of the largest plant generating at any moment (including the annual peak) and still meet the load. This implies that the minimum reserve requirement becomes the amount (percentage) of annual peak load served by the largest generator in the system. Many utilities base their capacity expansion plans on projections of capacity needed to meet at least this minimum requirement. Once it is

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*Other simulations are also widely used (e.g., grid stability and control, transmission and distribution).

**The sources available include all conventional interconnected sources not down for maintenance. However, only those conventional sources actually controlled by the utility system under investigation are explicitly modeled. While contracts for purchasing firm capacity and energy from interconnected utilities can be treated like conventional generators, at a practical level there is considerable variation in purchased-power characteristics. Large firms enjoy decided market advantages in contract negotiations. In emergencies, contracts for firm power may not be honored. On the other hand, even without firm contracts there are strong economic and regulatory incentives to share reserves across utilities whenever possible, especially in emergencies. Thus, utility boundary definition is an important analytic problem.

determined that additional capacity is required, well-known algorithms can be employed to determine which types of conventional generation to add.

While this conception of generation reliability may have been adequate for planning conventional capacity expansions, it suffers from two defects that are seriously exacerbated by the use of weather-dependent sources and load-management techniques. First, reserve margin considers grid failure at only a single point during the entire year--the annual system peak. The relative likelihood of failure at other points is ignored. Thus, the number of days during which the system approaches its peak is irrelevant. Consider the case of adding run-of-the-river hydro capacity in a summer-peaking utility where the hydro is available for only half of the year--in the winter and spring. This capacity would have no effect on the reserve margin (would get no capacity credit) even though it would clearly lower the probability of system failure during the winter and spring (assuming that that probability is not already negligible) and possibly even the summer if maintenance scheduling becomes more flexible as a result. It is this deficiency that has led to a new formulation of grid reliability--the Loss-of-Load Probability (LOLP).

A second deficiency in using reserve margin as a measure of grid reliability is the lack of an explicit stochastic formulation. No attempt is made to model the actual stochastic behavior of demand or forced outages. In fact, the basic parameters are expected values: the expected annual system peak and the expected system capacity available at that time. Given the large random component of weather-dependent sources' output profiles, this omission becomes more serious.

The Loss-of-Load Probability is often defined as the number of days during a year that the daily peak demand is expected to exceed the capacity available. Essentially, LOLP extends the concept of reserve margin from a single annual observation (the annual peak) to 365 annual observations (the daily peaks). This requires consideration of which sources will be available every day during the year and, therefore, more careful attention to maintenance scheduling. With a further assumption about the serial correlation of daily system failures (usually assumed to be independent, a dubious assumption) the expected number of daily grid failures per year can then be calculated. This is the LOLP. An arbitrary constraint can then be established for capacity expansion planning purposes, such as LOLP less than one day every 10 years.

Even with this elaboration, the reliability specification is still inadequate for a proper analysis of photovoltaics. The daily peak specification of LOLP is adequate to handle variations across seasons, but is unable to distinguish fluctuations over the course of a single day. Since daily system load peaks greatly exceed daily troughs, the probability of generation failure also fluctuates through the day. Further, since the stochastic variations in weather-dependent (especially solar electric) sources also have frequencies much shorter than a day, shorter sampling intervals are required to capture these potentially important variations. For example, many utilities have daily peaks that occur in late afternoon. Even though the maximum total output of fixed tilt arrays will usually occur when they are facing due south, it may still pay to face them west or southwest to shift the peak PV output to the afternoon. To capture the effects of daily fluctuations, hourly sampling intervals are employed by the PV Program.

Hourly reliability simulations must include an hourly (or more frequent) elaboration of LOLP in their formulation, such as expected hours of capacity deficiency or expected unserved energy (UE), which includes the extent as well as the duration of expected capacity deficiency. In actual applications, the UE implied by the analyzed utility's existing capacity expansion plan is often used (if the utility does not supply such a constraint). In addition, PV Program reliability simulations include a stochastic formulation of conventional capacity forced outage.

The procedure is as follows: first, the reliability (UE) of a utility's conventional capacity (as projected) is calculated for the year under investigation (e.g., 1995), without including any PV in the mix. Then the same reliability calculation is made with a specified quantity of PV included in the mix. If the UE falls, PV improves the reliability of the grid and can be used to defer capacity--portions of conventional units can be deferred up to the point where the UE rises to its original value.

However, the new load curve net of the PV is treated deterministically in existing reliability and production cost simulations (except for stochastic treatments of conventional-unit forced outage). That is, although the actual weather fluctuations from one year's weather observations are reflected in the new load curve, no attempt is made to consider changes in the uncertainty of the load seen by the conventional generators. In addition, the year chosen for analysis is usually selected based upon the availability and quality of data, not because any attempt has been made to characterize the selected weather year as typical or appropriate for design reference. These limitations affect the confidence we can place in the reliability calculations.

3. UTILITY SIMULATION: CAPACITY EXPANSION PLANNING

In general, a wide variety of different combinations of conventional capacity deferrals in the presence of photovoltaic capacity could return the UE to its original value. To choose the best units to defer (that is, the optimal generation mix), all combinations are searched for that combination of deferrals that results in the largest savings both in capacity (capital) costs and in fuel and other O&M costs.

In addition, optimization of the capacity expansion path needs to be undertaken, to reflect properly the shorter lead times and modular nature of PV additions. This optimization should be done over the lifetime of the PV systems. To be accurate it must capture many complex and subtle effects, including variations of: (1) sunlight and temperature in their daily and seasonal cycles as they interact with electricity load and outputs from PV and other generation sources for each utility district in the nation; (2) risk exposure due to the relatively short lead times and modular nature of PV additions; and (3) cash flow and debt burdens due to the high first cost of PV systems.

Existing calculations capture only some of these effects. Most analyses have confined their scope to delineation of an optimally configured grid including a given quantity of PV systems in some relatively distant future year (e.g., 1995). Only that year is simulated. Neither the path from the present to that date nor the consequences of various grid configurations for

future expansion beyond the year optimized are considered. Thus, while the grid is optimized to serve the assumed load* in (say) 1995 at least cost, the consequences of this for the rest of the expansion plan are ignored. Nevertheless, the simulations and optimization of a single year involve considerable complexity and can yield significant insight into PV interactions with utility systems. Development of more comprehensive techniques is receiving considerable attention from several research groups. A particularly ambitious undertaking has been funded by the Electric Power Research Institute (with DOE cooperation). They have contracted for a major two-year development effort by the MIT Energy Laboratory aimed at producing a utility capacity expansion planning model that will include weather-dependent technologies.

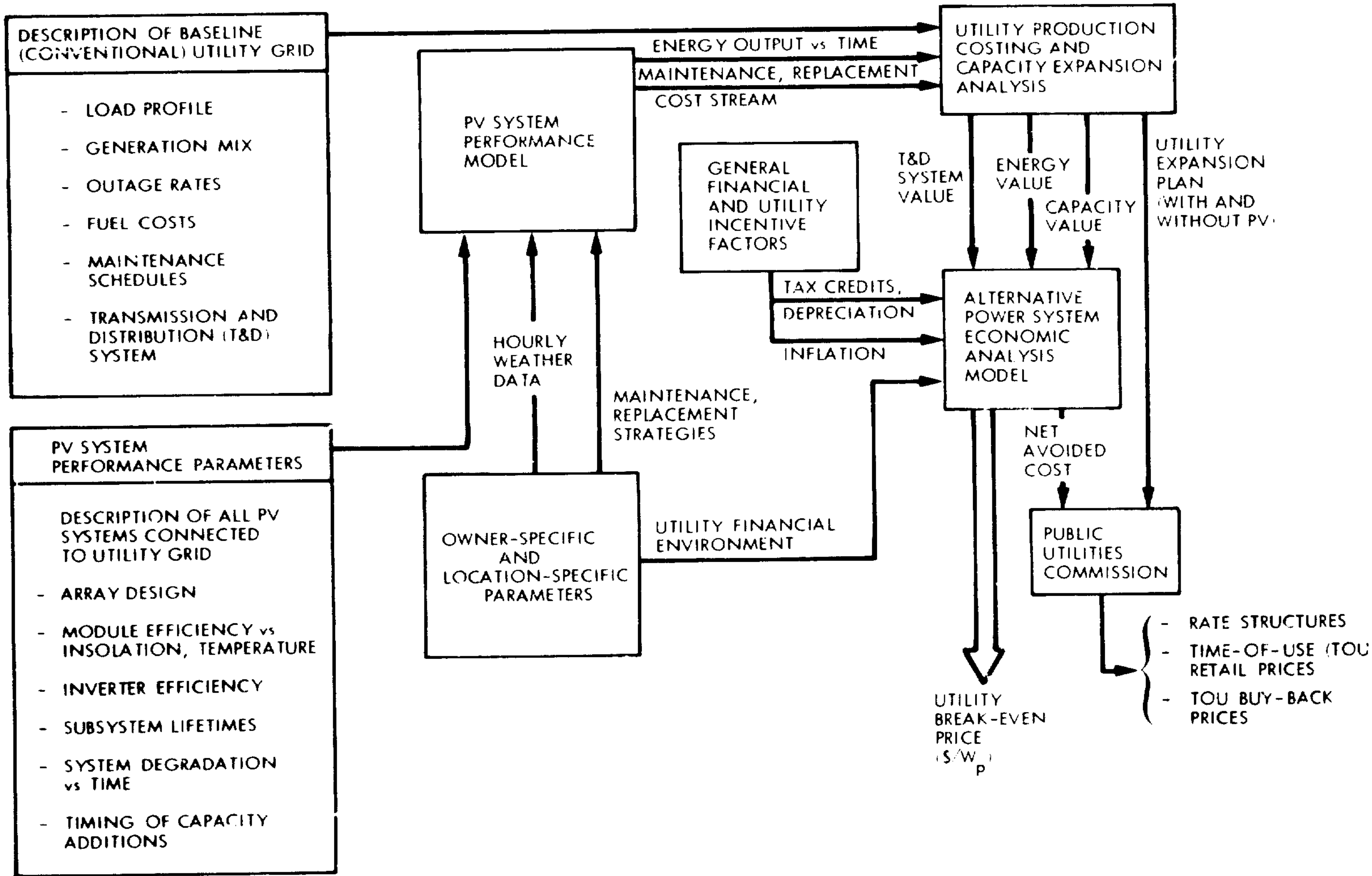
4. UTILITY SIMULATION: UTILITY SYSTEM PERFORMANCE AND PRODUCTION COST

In the short run, a utility does not have the option of additional capacity although it often can purchase power from neighboring utilities and for very short periods (less than 30 minutes) can overload its conventional generators. The problem facing utilities is to operate their systems to meet a fluctuating power demand at minimum cost. (In some cases, pollution-control objectives are also incorporated in scheduling algorithms.) The demand for electricity generally follows a predictable daily pattern, with peak periods often occurring between noon and early evening (although seasonal variations and variations among utilities are substantial). Utilities adjust their generating plant availability and use according to these changes in demand. Generating plants with low operating costs (base-load) are run much of the time. Plants with high operating costs are brought on line during the peak hours. Thus as a utility increases its output, the short-run marginal cost of generation increases, as does the risk of system failure.

In actual practice the scheduling and dispatch of modern utilities is a complex management task that cannot be completely reduced to simple algorithms. Scheduled and forced outages, drought, transmission difficulties and limitations, plant characteristics of start-up and shut-down times and costs, and efficiencies at differing output levels enter into decisions of which plants to dispatch, how much purchased power to use, which units to keep in spinning reserve, etc. The production cost simulation is intended to capture the essential elements of this set of conditions that bear on expected short-run fuel and maintenance costs. The expected load must be met from available sources (the dispatch simulated) and the resulting fuel and other costs calculated. The result is a detailed estimate of the fuels burned over the course of the year as well as the total operating costs incurred.

Figure 2 shows the analytical structure described above for simulating the savings of utility fuel and capacity resulting from PV additions.

*For reasons introduced above the optimization is, strictly speaking, valid only for the specific load and PV output profiles assumed.



SOURCE: "Introduction to Photovoltaic Program Price Goals," Tom Hamilton, JPL Memo, June 1980

Figure 2. Utility Simulation: Calculation of Utility Break-Even Prices and Buyback Rates (Owners of PV Systems May or May Not Be Utility)

C. CALCULATING BREAK-EVEN PRICES

After calculating the direct fuel, capital and other costs saved by the utility as a result of PV generation, it is still necessary to translate those savings into a figure of merit that accurately describes the actual effect of the PV system on the balance sheet of the prospective system owner. The most widely accepted figure of merit is the net present value (NPV) of the total expected savings of the PV system over its lifetime.* This NPV represents the total economic value of the PV system (expressed in constant dollars) and can therefore be directly compared with the total cost of the PV system--that is, the NPV of expected expenditures on the PV system during its lifetime. In order to solve for the break-even purchase price of the PV system, one simply subtracts from the value of the system (NPV of total savings) the NPV of all other PV system costs (except the purchase price). This value represents the maximum sales price a PV system owner could afford to pay for the installed PV system and still incur total expenditures for electricity no greater than he would with the best alternative electricity source. This break-even price can then be compared to the required price of PV system suppliers as described above (see Figure 1). Note that with this formulation all the tax and financial parameters of the system owner enter through the break-even price while those affecting the system suppliers affect the required price. For example, a solar tax credit for system buyers would affect break-even prices (the prices the purchasers could afford to pay for PV) while a subsidy to solar builders would affect the required prices (the prices required to cover PV suppliers' costs).

The actual after-tax effects of a photovoltaic investment on the balance sheet of a potential investor depend upon a myriad of details concerning that particular investor's tax and financial status. To handle these complicated accounting relationships, JPL has developed an interactive computer model called the Alternative Power System Economic Analysis Model (APSEAM). APSEAM incorporates, in detail, the local, state and federal tax treatments (e.g., income, sales, and property taxes; depreciation; capital gains; solar subsidies) of various potential PV investors (e.g., homeowners, utilities, businesses). The model simulates the flow of funds through a company's or individual's books. Yearly cash flow detail is determined and then aggregated into net present values and other figures of merit.

A serious complication is introduced into the analysis when prospective non-utility owners of PV systems are considered. The capital and fuel costs saved by a PV system are realized directly by the utility that owns it. Thus, these savings can be directly translated into after-tax cash flow savings of the utility. For non-utility owners, however, the savings are realized only indirectly--the savings of utility fuel and capacity charges must be transmitted through electricity prices (the rate structure) before they can be realized by non-utility PV system owners.

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*Other possible figures of merit include payback period, internal rate of return, and bus-bar energy cost. NPV is most rigorous and convenient for our purposes.

D. UTILITY RATE STRUCTURES

Utility rate structures differ widely across the nation. Flat declining block and flat inverted block* based upon historical utility costs are probably the most prevalent, but differences among levels, among residential, commercial and industrial classes, and among hookup, backup, utility lifeline and cogeneration rates are very substantial. Oil price increases have created great disparity (as much as a factor of 3) between the prices paid per oil-fired kWh and per kWh from coal, nuclear and hydro.

Much has been written about the efficiency and equity of various rate structures. Economists have long argued in favor of rates based on marginal cost, using both time-of-use and replacement-cost concepts. The efficiency of these rates has led Congress to resolve in their favor in the recently enacted Public Utilities Regulatory Policies Act of 1978 PURPA, (PL 95-617), requiring all utility commissions and non-regulated utilities to consider their adoption. Nevertheless, state regulators still have great latitude, and existing rate structures presumably bear some relationship to the existing balance of political power of various groups as reflected in the public-utility rate-setting process.**

Thus it is impossible to predict the evolution of rates in general or of specific sets of rates. It seems likely that a wide diversity of rate-setting philosophies and practices will be maintained for some time. Analyses of photovoltaic break-even prices have usually assumed the existing rate structure, primarily flat rates, although marginal cost (time-of-use) pricing is sometimes considered. Usually the rates for purchase of back-up power by the PV owner have been assumed not to differ from the rates charged non-PV owners of the same rate class (that is, there are no special PV back-up rates or demand charges employed). All of the utility fuel and capacity cost savings are reflected in the sellback rate--the rate at which excess PV power is sold to the utility. Utilities with large conventional cost savings as a result of PV have relatively high sellback rates and vice versa.*** The interaction among PV systems, electricity consumption patterns, and various rate structures has not been thoroughly investigated.

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*Traditionally, utility rates have declined as the purchaser consumed more power per period--that is, as he moved into higher consumption blocks. Recently, many utilities have inverted this structure by charging higher rates for higher consumption blocks.

**In addition, rate structures often have important practical constraints arising from metering costs. Leading utilities are now at the beginning a lengthy process of replacing existing meters with new technology. The primary motivation is increased productivity through the elimination of manual meter reading, while simultaneously satisfying PUC and economic requirements for load management and conservation. There is no guarantee that PV metering needs will be adequately incorporated.

***While our conception of rate structures may or may not reflect the truth about PV, it is clear that it does not reflect much of the practical realities of rate-setting in a regulated environment. Thus, practical advice on the design of PV rates for utility regulators and rate designers is desirable.

Congress has specifically addressed in PURPA the issue of rates for small power producers and cogenerators. Final rules have recently (March 1980) been promulgated by the Federal Energy Regulatory Commission (FERC) for PURPA with regard to these rates. Congress stipulated that the rates at which electricity is sold to the small power producer (photovoltaic owner) must be "just and reasonable" and, simultaneously, the sellback rates at which power is bought by the utility from the small power producer must be "equitable." FERC has interpreted these instructions in a manner consistent with the marginal cost-pricing principles that economists have advocated. That is, FERC established the principle that sellback rates must be set such that the entire net avoided costs* of the utility be returned to the small power producer or cogenerator while, simultaneously, the general consumers of utility power do not subsidize the purchase or operation of a small power producer or cogenerator.

With rates established in this manner, the non-photovoltaic customers of the utility will be no worse off and possibly better off with photovoltaic power systems operating within the utility than they would have been without the PV systems in existence. This implies that the rates charged to non-photovoltaic users are no higher than the rates that would exist were there no photovoltaic power systems buying and selling power back to the utility. It is assumed in this discussion that the rate schedule at which a utility sells power is the same for all customers, both photovoltaic and non-photovoltaic, of a given rate class. That is, the rate class is based solely on load and other non-PV related characteristics of the user. The amount the utility can pay for the electrical power it buys back from the photovoltaic generators should equal the difference (at the margin) in the utility's operating and capital costs induced by the addition of integrated, distributed photovoltaic power systems (that is, the marginal net avoided costs). With this condition, the total dollar amount of sellback revenue that can be applied to any level of penetration of photovoltaic systems within any utility system is uniquely defined, although there are many different rate structures that fit this constraint.

For non-utility owned photovoltaic systems the sellback rate assumes great importance. It determines both the existence and degree of cross subsidies between photovoltaic and non-photovoltaic utility customers and the economic viability of non-utility owned photovoltaic systems. PV Program break-even price calculations use sellback rates established as a result of PURPA whenever they are available. Figure 3 shows the analytical structure used to calculate break-even prices for non-utility PV owners given electricity rates.

This concludes discussion of the techniques employed to calculate break-even prices. The next subsection will discuss some of the limitations of those calculations. The break-even price discussion is concluded with a summary of existing results.

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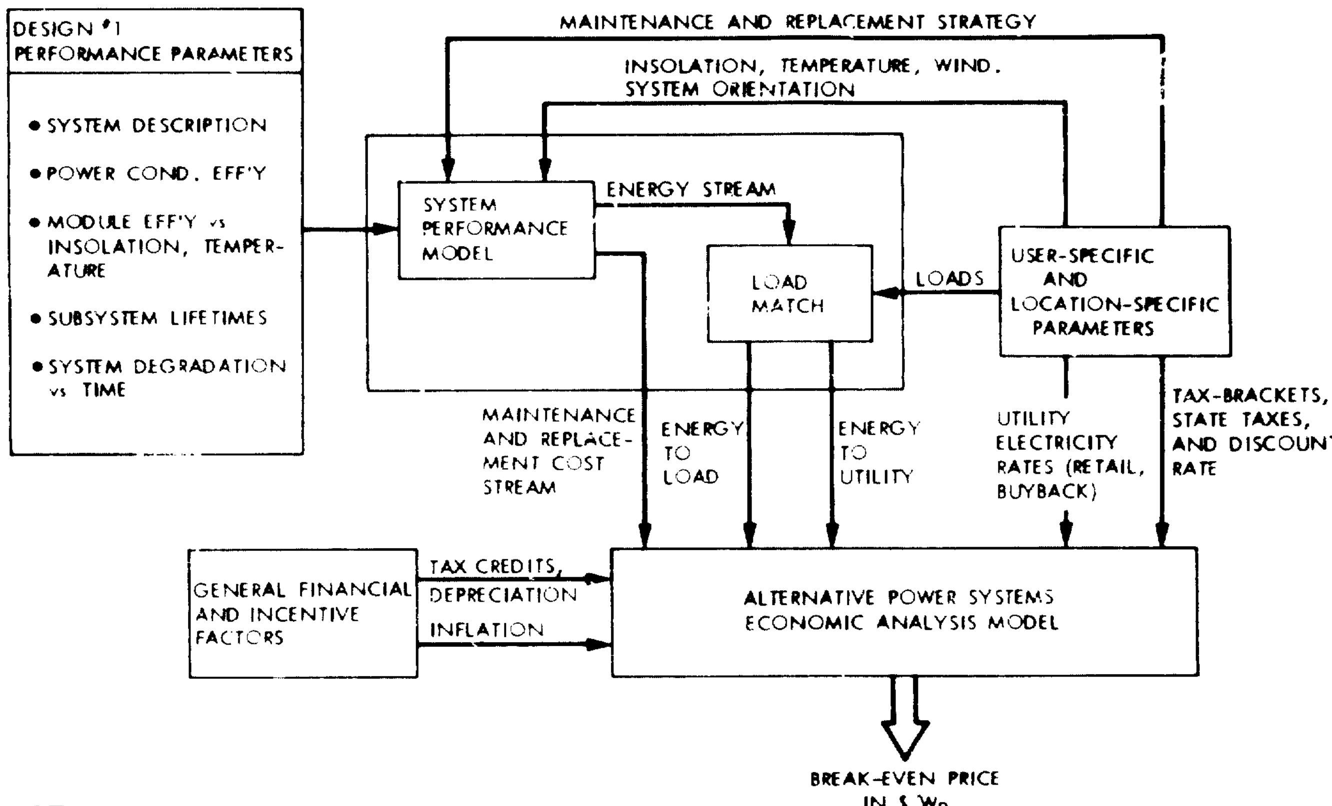
*Net avoided cost is essentially the marginal product of the PV system, at least for early PV units. There is uncertainty as to whether the actual application of net avoided cost will result in marginal or average product pricing (the marginal product of PV systems decreases with increasing PV penetration in the grid), a potentially serious ambiguity.



NOTE:

IN ADDITION TO THE BREAK-EVEN PRICE CALCULATION DESCRIBED IN THIS FIGURE, THE MODELS SUPPORTING THIS ANALYSIS CAN INCORPORATE PV SYSTEM PURCHASE PRICES (COSTS). THE SYSTEM PERFORMANCE MODEL WOULD THEN BE UTILIZED AS THE LIFETIME COST AND PERFORMANCE MODEL. FURTHER, THE ALTERNATIVE POWER SYSTEMS ECONOMIC ANALYSIS MODEL CAN GENERATE ANNUAL CASH FLOWS, FINANCIAL SUMMARIES, AND VARIOUS INVESTOR FIGURES-OF-MERIT.

SOURCE: PHOTOVOLTAIC PROGRAM PRICE GOALS, Tom Hamilton, JPL MEMO, JUNE 1980

Figure 3. Break-Even Price Calculation for Potential Purchaser of Residential System Design #1 Given Electricity Rates.

E. LIMITATIONS OF BREAK-EVEN PRICE CALCULATIONS

The formulations of break-even and required prices presented here provide convenient tools for summarizing the economic trade-offs facing PV Program management. Nevertheless, these concepts have serious limitations, some of which have already been mentioned. This section briefly describes additional defects in the break-even price concept which arise from its definition and from a lack of adequate data.

The data limitations are quite serious. Besides those discussed previously, problems arise in long-term projections (especially for estimates of future conventional fuel and capacity prices) and estimates of other nonobservable parameters to which break-even price results are quite sensitive (e.g., real discount rates). It is only a slight exaggeration to say that the ultimate success or failure of photovoltaics hinges on the future prices of coal and nuclear-fueled electricity production within the range of prices presently projected for these sources by competent observers. Differences in assumed real discount rates account for a significant portion of the calculated difference in central-station and distributed PV system break-even prices (see below).

An additional limitation arises from the narrow scope of alternatives we are able to investigate. Conventional sources are usually considered as competitors to PV, for example, without allowance for geothermal, cogeneration, or other renewables (unless contained in utilities' present expansion plans). Increased uncertainty in load growth forecasts have not been adequately examined. Finally, the large quantity of data required to produce even one point estimate of break-even price is largely responsible for the current lack of flexibility in making numerical economic trade-offs.

Of two conceptual limitations on break-even price estimates, the first may be quite serious: the omission of any attempt to measure differences in risk and liquidity among the investment alternatives a potential PV investor faces. Break-even price is an expected value. Only the means of the distributions of returns from the various investments are considered--neither potential risk exposure nor loss of liquidity are explicitly considered in break-even price calculations. For example, a typical homeowner faces severely different effects on his asset portfolio from investing in a $15,000 roof-mounted PV system as opposed to continued purchases of electricity from the utility. These portfolio changes probably cannot all be captured in interest rates and insurance premiums. A second difficulty arises from the assumption that PV kilowatt hours are identical to those of the competition. If this is not true, or if the production function into which PV electricity is an input is allowed to change, the resulting final product is likely to differ. This would imply that consumer utility functions must be considered in the comparison. For example, a remote village considering PV with storage as an alternative to diesel power must consider such things as the acceptability of power generation outages related to long cloudy periods.

F. RESULTS OF BREAK-EVEN PRICE CALCULATIONS

Break-even prices for photovoltaic systems have been published by several sets of investigators around the country, including the PV Program. At this

point no organization maintains a validated on-line capability of producing such estimates, due partly to the rapidly changing and complex set of analyses thought to be required, partly to disagreement over what is required and with what priority, and partly to lack of sufficient appropriate resources. JPL is actively pursuing the capability of performing break-even price calculations and sensitivity analyses easily, accurately and quickly.

Table 1 presents summaries of the results of major utility break-even price analyses conducted to date by five different investigators. These numbers represent the estimated value as realized by the utility of the savings in conventional costs occasioned by the presence of the PV systems per watt of PV rated capacity. As such, they are an average value (marginal values are lower). In general, the results range between \$.40 and \$1.00/W_p, but extend significantly higher and lower if non-base-case assumptions are made. The PV Program has selected a range of prices (\$1.10-\$1.30/W_p) within which it intends to set a goal for development of PV systems for central station applications by 1990. Thus, the goal lies 10% to 30% above the range predicted by the authors of these studies as the most likely break-even price.

There are significant reasons to believe that these studies may be underestimating the actual future value of PV systems, however. Most of these reports are several years old. Most do not include real escalation in conventional fuel and capital costs in their base-case. But electricity production costs and difficulties have grown substantially in the interim. Coal and nuclear construction costs continue to escalate and their use grows more restricted. Real costs of conventional fuel, pollution control, and transportation are also increasing. It is possible that an update of input assumptions would increase these break-even prices. Also, as discussed above, these estimates do not reflect either the potential external benefits of PV (fuel security, pollution freedom) or the increased flexibility of capacity expansion resulting from shorter lead times and modular additions.

Table 2 presents a summary of results of recent analyses that have calculated the savings in electricity costs as realized by potential residential PV system owners. As noted above, these analyses are dependent on the assumed rate structure the PV owner faces and on assumptions concerning his investment and financial status. Since the rate structures must themselves be a function of the utility savings as calculated above, these estimates suffer from all the uncertainties therein as well as those introduced by the unique aspects of non-utility ownership.

The results in Table 2 are significantly higher than those shown in Table 1. The sources of these higher break-even prices for residential PV owners are not well understood. However, these analyses have generally assumed significant real escalation in electricity prices, in contrast to the utility-owned analyses summarized above. Also, more favorable financial assumptions are often employed in the distributed (especially residential) cases.

Whatever the source of these higher distributed break-even prices, they lend support to a distributed PV development effort. The PV Program has selected a price goal of \$1.60/W_p for grid-connected distributed systems, to be achieved in 1986. This goal is clearly within the range of distributed break-even prices shown in Table 2.

Table 1. Utility-Owned Flat-Plate Photovoltaic System Break-Even Prices (1980 $\$/W_p$)[a]

Stone and Webster

Southwest[b]		Salt River Project[c]	Southern California Edison	Arizona Public Service
	Capacity	.127	.093	.237
	Fuel	1.024	.741	.212
	O&M	-.120	-.072	-.084
	Total	1.031(3.021)[d]	.762(1.577)	.366(.783)

Southeast:[e]		Baltimore Gas and Electric		Florida Power and Light	
		0% real fuel escalation	4% real fuel escalation	0% real fuel escalation	4% real fuel escalation
	Capacity	.366	.330	.277	.270
	Fuel	.132	.690	.256	.790
	O&M	-.080	-.080	-.068	-.070
	Total	.388(.280)[f]	.940	.466(.379)	.990

Westinghouse[g]		Privately Owned (Phoenix)	Publicly Owned (Phoenix)
	Capacity	.016	.016
	Fuel	.609 (.857)[h]	.894 (1.270)
	O&M	.057	.082
	Total	.682 (.929)	.992 (1.370)
	Range[i]	.677 - 1.56	.986 - 2.220

See footnotes starting on p. 23.

Table 1. Utility-Owned Flat-Plate Photovoltaic System Break-Even Prices (1980$\$W_p$)[a] (Continued)

Science Applications, Inc.[j]	100kW Flat Panel (Fort Worth)	25 MW Flat Panel (Forth Worth)
Capacity	.348	.401
O&M	.070	.069
Coal	.418	.346
Oil/Gas	.281	.277
Total	1.047	1.093
Range	.841 - 1.302	.808 - 1.285

MIT Energy Lab[k]	Midwest	Northeast	Southeast	Southwest
Capital	.136	.269	.284	.262
Fuel	.273	.433	.605	.748
O&M	.017	.006	.008	.007
Total	.424	.707	.896	1.02
Range[l]	.398 - .424	.665 - .707	.860 - .896	.974 - 1.02

GE Study[m]	FP&L[n]	APS/SRP[o]	NEES[p]
Production cost[q]	.543	.308	.463
Capacity	.096	.492	.252
Total	.639	.800	.715
Range[r]	.548 - .872	.747 - .931	.638 - .914

See footnotes starting on p. 23.

Footnotes: Table 1

(a) The results reported here are those that the various studies characterize as their base case (if they so characterize a case). Except for convert ing to present values in 1980 $, no attempt has been made to convert the various studies' results to a common assumption base. In general, the studies calculated and reported average rather than marginal PV product.

(b) Source: "Southwest Project; Resource/Institutional Requirements Analysis, Volume III-Systems Integration Studies," Stone and Webster Engineering Corp., December 1979. (See Sections 5 and 6, especially Table 6.6.1). A 100-MW_p flat-plate lean-to PV system was assumed. Inflation, capital, and O&M escalation rates were assumed to be 6%/year. Base year was 2000.

(c) A fixed charge rate (FCR) of 11.88% was assumed for SRP, a publicly-owned utility. A weighted-average nominal fuel escalation rate of 6.3% was assumed for SRP. For the privately-owned utilities SCE and APS, FCRs of 19.62% were used. For SCE a nominal fuel escalation of 6.7% was employed, while APS's was 4.9%. The SRP base case used a solar penetration level of 5% of rated capacity; SCE and APS used 10% penetration.

(d) The figures in parentheses were determined by multiplying the total break-even investment by the multipliers for 10% nominal fuel escalation (4% real) as seen in Figures 6.6-17, 6.6-22, and 6.6-26 of the source. The multipliers used were SRP--2.93; SCE--2.07; APS--2.14.

(e) Source: "Southeast Regional Assessment Study--An Assessment of the Opportunities for Solar Electric Power Generation in the Southeastern United States," Stone and Webster Engineering Corporation, July 1980. (See Section 5, Tables 5.3-1, 5.3-6.) The base case assumes a penetration rates of 3.7% for Baltimore Gas and Electric (BG&E) and 3.9% for Florida Power and Light. Inflation, capital and O&M escalation rates of 6%, and a 100 MWp system size were used. Base year was 2000. For BG&E the FCR = 14.9%. For FP&L the FCR = 18.92%.

(f) In parentheses are break-even values for the case of 15.7% penetration. This case yielded the lowest break-even values of the four cases presented in the study. (The highest was the base case).

(g) Source: Pittman, P.F., "Conceptual Design and Systems Analysis of Photovoltaic Power Systems, Final Report, Volume 2. Systems," Westinghouse Electric Corp., for the U.S. Department of Energy, Pittsburgh, Pennsylvania, March 1977. (See Tables 3.4.2 - 3.4.4). The base case was a fixed-array, lean-to, central-power station located near Phoenix. Fuel costs were assumed to be (1980 $): coal 0.67/MBtu, nuclear 0.56/MBtu, and oil 2.79/MBtu. Fuel escalation rates were assumed to be (nominal): coal and nuclear 5%, oil 8%. Base year is 1990. Other assumptions unspecified (6% inflation rate was assumed by JPL in conversion to 1980 $). FCR = 18% for privately-owned utility. FCR = 12% for public-owned utility.

Footnotes: Table 1 (Continued)

(h) Values within parentheses were calculated with high fuel cost assumptions (1980$):

Coal:	1.00$/MBtu	6% escalation/yr
Nuclear:	0.78$/MBtu	8% escalation/yr
Oil:	3.35$/MBtu	8% escalation/yr

(i) The range reflected different PV system designs and fuel escalation: fixed-array windrow with moderate fuel cost assumptions (low end), vertical axis tracking with high fuel cost assumptions (high end).

(j) Source: "Regional Assessment Study--South Central Region, Volume II--Solar Electric Deployment Opportunities," Third Quarterly Progress Report, Science Applications, Inc., February 1980. (See Tables 3.3-6 and 3.3-8 and Figure 4.1-23 and 5.1-20.) The study used an EPRI synthetic utility. The solar plants were assumed to be located near Fort Worth, Texas. Base-case assumptions included 6% inflation, 8% escalation for capital and O&M costs, nuclear and coal fuels, 8.5% for distillate fuel, 9% for residual oil, and 10% for natural gas. Base year was 1990. Since the results of the report were presented in levelized 1980 $/yr, they were divided by the capital recovery factor to derive present values.

(k) Source: Reference 3, Vol. II, Appendix B. The MIT analysis used four EPRI synthetic utilities and load data from Boston Edison for the Northeast, Omaha Public Power for the Midwest, Florida Power and Light for the Southeast, and Arizona Public Service for the Southwest. The study assumed 0% real capital escalation and 3% real fuel escalation. As a base case, the results with lowest penetration were chosen, amounting to 6.1% in the Northeast, 6.2% in the Midwest, 9.2% in the Southeast, and 10.5% in the Southwest. Base year was 1976.

(l) The high penetration case--18.3% in the Northeast, 18.1% in the Midwest, 18.3% in the Southeast and 15.9% in the Southwest--gave the low end of the range.

(m) Source: "Requirements Assessment of Photovoltaic Power Plants in Electric Utility Systems," General Electric Company, Volume 2, ER-685, June 1978. (See Section H.) Assumptions for the base case included: PV penetration of 5%, fuel escalation of 6%, a FCR of 15%, and inflation of 6%. The plant size was 200 MW_p. Rather than optimizing the system mix, GE assumed that all displacement comes from one capacity class (nuclear, coal, etc.). For each utility, the capacity class that gave the highest PV value was assumed to be the class displaced. Base year was 1995; 1995 fuel prices (1980 $/MBtu) assumed were nuclear 0.668, residual 2.38, and distillate 3.00.

(n) Florida Power and Light. Capacity displaced was assumed to be combined cycle.

Footnotes: Table 1 (Continued)

(o) Arizona Publi Service/Salt River Project. Capacity displaced was assumed to be coal; 1995 fuel prices (1980 \$/MBtu) were coal 0.375-1.29, residual 2.59-2.75, and distillate 2.71-3.30.

(p) New England Electric System. Capacity displaced was assumed to be oil-fired steam.

(q) Production cost included fuel costs and O&M credits.

(r) Low end of range had FCR = 18%; high end of range had 9% nominal fuel escalation (3% real).

Table 2: Non-Utility-Owned Distributed Flat-Plate Photovoltaic System Break-even Prices (1980 $\$/W_p$)

Department of Energy (MIT Energy Laboratory)[a]					
Rate Structure[b]		Phoenix	Boston	Miami	Omaha
Flat:	Embedded	2.06	1.50	1.89	1.25
	Replacement	2.37	2.04	2.42	1.55
Time of Use:	Embedded Non-Allocated	2.02	1.50	1.86	1.16
	Embedded Allocated	1.92	1.50	1.89	1.23
	Replacement Allocated	2.25	2.84	2.42	1.50

General Electric[c]					
	Boston	Phoenix	Miami	Omaha	Fort Worth
base-case	1.63	2.22	1.48	1.13	.93
high	3.20	4.35	2.90	2.22	1.82
low	1.11	1.51	1.01	.77	.62

Department of Energy (JPL)[d]			
Application	Phoenix	Miami	Boston
Residential[e]	1.35 - 1.80[f]	.85 - 1.20	1.30 - 1.75
Commercial/Industrial[g]	1.45 - 1.90	1.15 - 1.55	1.00 - 1.35

See footnotes starting on p. 27.

Footnotes: Table 2

(a) Source: Reference 3, Vol. II. The MIT analysis used data from four EPRI synthetic utilities and load data from Boston Edison for the Northeast, Omaha Public Power for the Midwest, Florida Power and Light for the Southeast, and Arizona Public Service for the Southwest. The study assumed 0% real capital escalation and 3% real fuel escalation. Base year was 1976. PV sell-back revenue was taxed as income, and the portion of PV system costs attributable to the generation of power for sell-back was assumed tax deductible. State income taxes were estimated, but there were no solar tax credits or property taxes. System lifetime was 20 years.

(b) MIT assumed that rates will be set according to PURPA guidelines, implying that all costs displaced by the PV system will be returned to owners through an appropriate sell-back rate (except that an average rather than a marginal concept was employed). Thus the MIT sell-back rate varies according to the displaced costs of the utility and its rate structure. MIT analyzed five rate structures in which rates were charged: to recover either embedded (historical) or replacement capital costs; as flat rates or as time-of-use rates; and with capital recovery weighted and allocated by period of capital stock use or assumed recovered during peak hours.

(c) Source: E. J. Buenger, et al, Regional Conceptional Design and Analysis Studies for Residential Photovoltaic Systems, Executive Summary, Volume I, General Electric Space Division, Philadelphia, Pennsylvania, January 1979. GE computed the value of photovoltaic systems in terms of levelized annual cost/levelized annual benefit ratios. To derive the table entries shown, these ratios were inverted and multiplied by system costs to give the present worth of the benefit, which was converted to 1980 $ and divided by the peak capacity of the system. Base year was 1986. Base case assumptions were: 5% inflation, 10% mortgage rate, 30% tax bracket, no property tax, 4% real energy price escalation, 0.5 sell back-to- buy price ratio (the sell-back rate), no solar tax credits, and 20-year system life. High case corresponded to 6% real fuel escalation and a 30-year system lifetime. Low case corresponded to 2% real fuel escalation. This case (PV shingle, no storage) was one of the seven PV-only systems GE analyzed; with the systems differing in storage, charging, and array technology (flat-panel vs two-axis tracking concentrator). Only two of the systems used no storage with excess power sold to the utility. The PV shingle configuration gave the lowest cost/benefit ratios in all of the regions analyzed.

(d) Source: Reference 5. Assumptions were: inflation of 6%, no property tax, insurance rate of 0.3%, and a 30-year PV system lifetime.

(e) The residential application was a 10 kW_p system owned by the homeowner under the following assumptions: FCR = 0.08, after-tax discount rate = 0.005, marginal tax rate = 0.35, OM costs = 16.00 $\$/kW_p/yr$, sell-back fraction = 48%, power conditioning efficiency = 0.90, and sell-back rate = 50%.

Footnotes: Table 2 (Continued)

(f) The ranges of system prices correspond to the following ranges of assumed 1986 energy prices (in 1980 ¢/kWh).

	Phoenix	Miami	Boston
Residential	4.5 - 5.7	4.3 - 5.5	7.4 - 9.4
Intermediate Load	5.1 - 6.4	5.5 - 7.0	6.3 - 8.0

(g) The commercial/industrial application was a 100 kW_p to 5 MW_p plant owned by a private corporation under the following assumptions: FCR = 0.12, after-tax discount rate = 0.08, marginal tax rate = 0.40, depreciation is double declining balance, OM costs = 14.40 $/$kW_p$/yr, no sell-back, and power conditioning efficiency = 0.92.

Tables 1 and 2 reveal considerable variation in PV values among regions of the United States. Not surprisingly, the Southwest, represented by Phoenix, is the most attractive region for photovoltaics according to these studies. Recent unpublished investigations have indicated that California and Hawaii, with their high utility consumption of oil, may be the most attractive areas for PV deployment within the Southwest region. The tables also indicate that the Northeast (Boston) and the Southeast (Miami) may also prove to be viable photovoltaic markets. Other areas of the country (e.g., Omaha, Fort Worth, Baltimore) apparently require lower PV system prices to allow competitive application. While the value of PV clearly varies considerably across the United States, the accuracy of existing analyses does not yet allow more accurate or detailed delineation of this geographic variation.

In summary, primary development goals have been selected by the PV Program that, if achieved, have some probability (according to existing evidence) of approaching break even with conventional electricity sources and, thus, to beneficial employment of photovoltaic technology for bulk supply of electricity in the United States. However, significant ambiguities, limitations, and changing circumstances render the existing evidence uncertain. It is hoped that ongoing analytical activities will help to resolve these questions, increasing our insight into the promise of terrestrial application of PV systems.

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APPENDIX A

SOCIALLY OPTIMAL PRICE GOALS

The formulation of system price goals in terms of private market prices and conditions discussed at the beginning of this paper (see Figure 1) can be interpreted to be seriously at odds with a socially optimal formulation. How can we assume that private market prices reflect social costs when we know that there are serious market failures* (monopoly, pollution, national security) inherent in many aspects of energy production and supply? Should the goals not be corrected to account for these market failures? This is not done primarily because it cannot be done credibly. Arguments over the corrections would never cease and could strongly affect price goals and thus technical development activities; such corrections would therefore be generally non-productive for the PV Program. An important consequence of this omission is that PV Program trade-offs involving these market failures (e.g., trade-offs among various potential environmental effects of different PV collectors) cannot be done within the price goal structure. This has been countered programmatically by the formulation of arbitrary environmental acceptability criteria (e.g., NEPA requirements) as well as environmental research and control technology development activities to anticipate unwanted environmental consequences. Also, the private market formulation probably reduces the price goals, since, relative to conventional sources, PV makes positive contributions to society in most of the areas of energy market failure, including pollution, national security, and, possibly, monopoly.

As an alternative, the Program could interpret the many recent enactments of local, state, and federal solar incentives as government attempts to correct for market failures present in energy market prices. Under the heroic assumption that such incentives are perfect corrections for existing market failures, actual market prices (including the incentives) can be used in required price and break-even price calculations, and the results can be called socially efficient. However, positive incentives to solar and other new energy sources can never produce a Pareto solution and may move the economy away from the efficiency frontier if market failures result from negative externalities of conventional sources (e.g., pollution, national security). Only taxes applied against these conventional sources can fully correct for these negative externalities.**

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*The conditions under which private markets will produce socially optimal use, in a Pareto optimal sense, of the productive resources available to the economy are well known. A market failure occurs when one of these conditions (competition, no externalities, non-public goods) does not hold. Pareto optimality implies that no one can be made better off without making someone worse off.

**For discussion of related issues, see: Camm, F., "Policy Alternatives to the Average Cost Pricing of Natural Gas," Resources and Energy 2, 1979, North-Holland Publishing Co.

Since federal solar incentives are scheduled for expiration in 1985, and since their stated intention is to encourage temporarily a new industry rather than to correct permanently for market imperfections, they have not been included in the existing system price goals of the Program for 1986 and beyond. However, this omission has recently become controversial. The relationship between goals for technology development activities and the subsequent promotion of widespread utilization of resulting techniques, processes and systems is complex and poorly understood. The formulation of system price goals in terms of private market conditions has the added important benefit that, if achieved, private incentives (without special government subsidy) are likely to be sufficient to create a profitable private photovoltaic industry and market. As long as solar incentives are explicitly intended to be temporary inducements only, this condition must be met for Program success.